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Optimal combined scheduling of generation and demand response with demand resource constraints

Hyung-Geun Kwag, Jin-O Kim *

Department of Electrical Engineering, Hanyang University, Republic of Korea

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ABSTRACT

Demand response (DR) extends customer participation to power systems and results in a paradigm shift from simplex to interactive operation in power systems due to the advancement of smart grid technology. Therefore, it is important to model the customer characteristics in DR. This paper proposes customer information as the registration and participation information of DR, thus providing indices for evaluating customer response, such as DR magnitude, duration, frequency and marginal cost. The customer response characteristics are modeled from this information. This paper also introduces the new concept of virtual generation resources, whose marginal costs are calculated in the same manner as conventional generation marginal costs, according to customer information. Finally, some of the DR constraints are manipulated and expressed using the information modeled in this paper with various status flags. Optimal scheduling, combined with generation and DR, is proposed by minimizing the system operation cost, including generation and DR costs, with the generation and DR constraints developed in this paper.

1. Introduction

In current power systems, the efficient use of demand side resources has become important due to the restrictions for utilizing conventional generation resources. In addition, the recent advancements in smart grid technology, including auto-metering and communication, make it feasible to develop demand response (DR) with a program format that uses demand side resources practically. DR can be defined as the changes in electric usage by end-use customers compared to their normal consumption patterns [1]. According to the definition, the primary agents of DR are not the operators but the customers, who have the ability to exert favorable influences, such as improving system reliability and lowering the electric price, by participating in a Demand Response Program (DRP) [1,2]. DR allows the customer participation to extend to the power system operation, and the customers can play a key role in shifting the paradigm in the power systems because they have the ability to voluntarily control the loads as demand resources when the peak load increases, as opposed to the system passively supporting an increasing load with generation resources. In order to efficiently utilize the demand resources, it is important to model the customer characteristics in DR. Recent research [2] shows how customer behaviors can be modeled using an elasticity matrix composed of the price-elasticity of the demand. Refs. [3–9] show that customer responses have a positive influence on the power market performance, nodal price and reliability indices, available transfer capability and spinning reserve, based on the reference method [2]. Refs. [2–9] are seen as merely modeling customer response according to the changes in electricity price during a specific period of the day based on the constant elasticity matrix. In practical terms, however, the assumption of a constant elasticity matrix within a certain specific period is unreasonable, and moreover, the frequency of DR has yet to be modeled and restrictive results may be incurred by a method using an elasticity matrix. In addition, a lack of available information on response characteristics has the effect of incredibility of those methods because the price-elasticity of demand requires high credibility. For this reason, DRP operators request customer information necessary to operate the DRP. As an example, NYISO (New York Independent System Operator) is required to provide interruptible load rating, reduction lasting time, and response time [11,12]. In this paper, aggregated information and their relationships are modeled in a closed form expression. This paper also introduces the concept of virtual generation resources converted from demand resources, with their marginal cost calculated according to customer information. Some constraints of DR are manipulated and expressed using the information modeled with various status flags. Optimal scheduling, combined with generation and DR, is proposed by minimizing the system operation cost, including DR cost as well as conventional generation cost, with the generation and DR constraints developed in this paper.

* Corresponding author. Address: 17, Haengdang-dong Seoungdong-ku, Department of Electrical Engineering, Hanyang University, Seoul 133-791, Republic of Korea. Tel.: +82 2 2220 0347 (office), +82 10 9797 0347 (mobile); fax: +82 2 2220 1856.

E-mail address: jokim@hanyang.ac.kr (Jin-O Kim).

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2. Customer information

Demand resources desiring to participate in a DRP should provide some initial information on the demand resource characteristics prior to a DRP [11,12]. However, when a DR event is issued, the actual DRP response characteristics may not be identical to the initial information due to some of the demand resource constraints such as the capacity for available lasting response, automated or non-automated metering status, and the business schedule of individual customers. Therefore, it is necessary to collect historical DR data which includes the responsive characteristics of the demand resources after a DRP.

Generally, DR customer information can be divided into registration and participation information, used for more efficiently and accurately evaluating demand side resources [11,12]. Registration information is defined as a customer's initial information prior to registration, and participation information is the historical data collected after a DRP event, as shown in Table 1.

In this paper, we attempt to express the informational relationships using closed form equations, which include status flags for commitment state and beginning and ending states.

For the registration information, DR magnitude M^j [MW] is the maximum demand reduction which customer j is able to achieve. Duration ($D^j_{\min}, D^j_{\max}$ [h]) is the period of demand reduction available per a DR event, consisting of minimum and maximum durations. Frequency Fj [freq/yr] is the maximum number of yearly participation events in the DRP for customer j.

For the participation information, participation rate (PR) is defined as the ratio of j customer's load reductions to the DR magnitude at time t and can be represented by

$$\mathrm{PR}^j(t) = \frac{\mathrm{DR}^j(t)}{M^j(t)} \cdot s^j(t), \tag{1}$$

where $\mathrm{DR}^j(t)$ is the load reduction of customer j at time t (MW), and $s^j(t)$ is the DR commitment flag, either a 1 or 0 dependent on whether or not customer j reduces their demand at time t. Participation rate denotes the actual reduction level compared with the maximum DR magnitude available to be reduced.

Load response rate (LRR) is similarly defined as the ratio of j customer's load reduction to the customer baseline load at time t and can be represented by

$$\mathrm{LRR}^j(t) = \frac{\mathrm{DR}^j(t)}{\mathrm{CBL}^j(t)} s^j(t), \tag{2}$$

where $\mathrm{CBL}^j(t)$ is the customer baseline load (CBL) at time t, which is the average hourly energy consumption and is used to determine the level of load curtailment [11,12]. Load reduction is measured as the difference between the customer baseline load and the actual metered usage for a DR event. LRR denotes the ratio of load changes after a DR, to the total load. LRR can be used to calculate the price elasticity.

DR average duration [h/freq] is defined as the lasting time of load reduction per DR customer participation and can be represented as

$$d^j = \frac{\sum_{t\in T} s^j(t)}{\sum_{t\in T} b^j(t)}, \tag{3}$$

where $b^j(t)$ and $e^j(t)$ are the beginning and ending flags of a DR, respectively. The flags are set to 1 when customer j starts and ends reduction.

DR frequency rate [freq/h] is the number of participation events during a given time and can be represented as

$$f^j = \frac{\sum_{t\in T} b^j(t)}{T}, \tag{4}$$

where T is the length of time of the study in hours.

Fig. 1 illustrates situations for which DR events were issued and customer j responded to the corresponding DR events, where the first DR event occurred from hours 11 to 13 and the second event from hours 17 to 19. Customer j reduced his load by as much as $\mathrm{DR}^j(t)$ from $\mathrm{CBL}^j(t)$ during the DR events and did not participate at hour 19. The DR commitment flag for customer j was 1 when he reduced his demand. The DR beginning and ending flags were set to 1 when starting and finishing reduction, respectively. PR and LRR were calculated using the definitions stated above, where DR average duration and DR frequency were 2.5 and 0.0833, respectively.

3. Marginal cost of demand resources

This paper proposes the transformation of the demand reductions of demand resources into virtual generations of units. Increased demand reduction can be treated as an equivalent generation resource. It is able to replace the generation resource having a higher marginal cost by comparing the marginal cost of demand reduction and generation resource.

Fig. 2 shows supply and demand curves which denote the marginal cost of generation and load, respectively. The vertical line of the demand curve shows that none of the demand resources responded to the electricity price [10]. The variables π^j_l and π^j_h are the electricity prices when customer j started and finished responding to the DRP event, respectively. When a customer responds to the DRP, the load reduction, as much as $\mathrm{DR}^j(t)$ from $\mathrm{CBL}^j(t)$, creates the negative slope in the demand curve, demonstrating the characteristics of a typical demand curve. The curve shows that price-responsive customers have a finite marginal value of willingness to pay. The new vertical line shifted by an amount equal to DR represents infinite marginal values of price taking customers. Furthermore, the area below the negative slope represents the DR costs of all of the demand resources used in the DRP.

Demand reduction can be treated as virtual generation by calculating the marginal cost of the demand reduction. It can be consider that the marginal value of demand resources increases according to the amount of DR, i.e., demand reduction, and the negative quantity of the demand reduction resulting from the DR can be converted to a positive slope in the DR in order to draw an analogy with the supply curve, as shown in Fig. 3. The marginal cost, mc^j, of demand resources is the function of the load reduction of customer j, dr^j, and can be represented from Fig. 3 as

$$mc^j = \frac{\pi^j_h(t) - \pi^j_l(t)}{\mathrm{DR}^j(t)} s^j(t) dr^j + \pi^j_l(t) s^j(t), \tag{5}$$

where π^j_l and π^j_h are the electricity prices when customer j starts and finishes responding to the DRP, respectively.

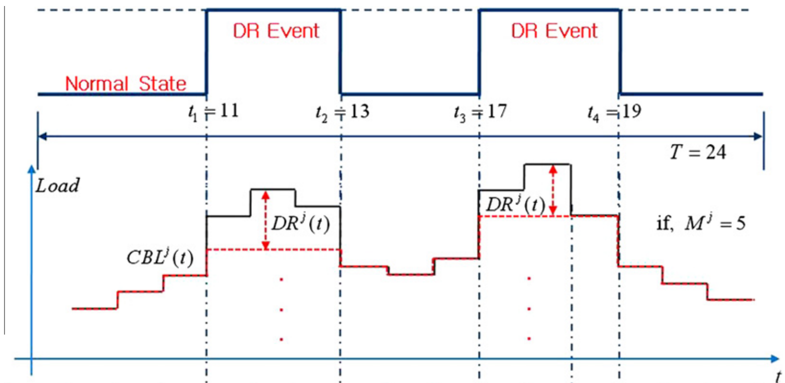
The linear expression of (5) can be rewritten, for simplicity, as

$$mc^j = \alpha^j(t) dr^j + \beta^j(t), \tag{6}$$

where $\alpha^j(t)$ and $\beta^j(t)$ are the first order coefficient and constant, respectively, of the marginal cost function of customer j and can be determined using (9) and (10), respectively.

Table 1
Demand response customer information.

Registration information	Participation information
DR magnitude	Participation rate
Duration	Load response rate
Frequency	DR average duration
	DR frequency rate
	Marginal cost



hour	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
$s^j(t)$	0	0	0	1	1	1	0	0	0	1	1	0	0	0	0
$b^j(t)$	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0
$e^j(t)$	0	0	0	0	0	0	1	0	0	0	0	1	0	0	0
$DR^j(t)$	0	0	0	2	3.5	2.5	0	0	0	1.5	3	0	0	0	0
$CBL^j(t)$	10	11	12	15.5	17	16	12.5	12	13	17	19	15.5	12.5	11.5	10.5
$PR^j(t)$	0	0	0	0.4	0.7	0.5	0	0	0	0.3	0.6	0	0	0	0
$LRR^j(t)$	0	0	0	0.129	0.206	0.156	0	0	0	0.088	0.158	0	0	0	0

Fig. 1. Example of calculating customer information of demand resources.

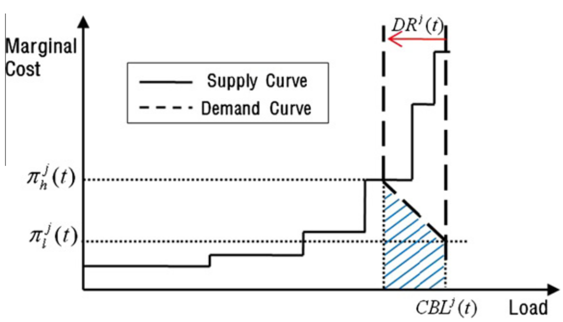


Fig. 2. Change in demand curve according to DR.

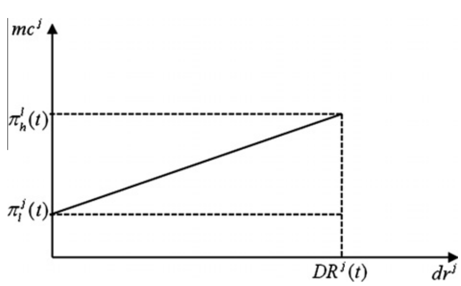


Fig. 3. Equivalent marginal cost of demand resources.

The marginal cost can also be expressed by the elasticity and load response rate of participation information. Generally, the price elasticity of the demand is defined as the relative change in the demand to the price deviation and is given by [1]

$$\varepsilon = \frac{\frac{\Delta D}{D}}{\frac{\Delta \pi}{\pi}}. \tag{7}$$

The demand at the equilibrium point and the change in demand in (7) can be replaced by $\mathrm{CBL}^j(t)$ and $\mathrm{DR}^j(t)$ from Fig. 2, respectively. Therefore, the elasticity of customer j at time t is defined using (2) and (7) such that

$$\varepsilon^j(t) = -\mathrm{LRR}^j(t)\frac{\pi_l^j(t)}{\pi_h^j(t) - \pi_l^j(t)}. \tag{8}$$

Eq. (8) is obtained by averaging the historical data for all of the events at time t. The first coefficient and a constant of the marginal cost of demand resource j can be rearranged using the elasticity and CBL of customer j from (2), (6), and (8) such that

$$\alpha^j(t) = \frac{\pi_h^j(t) - \pi_l^j(t)}{\mathrm{DR}^j(t)} = -\frac{1}{\varepsilon^j(t)}\frac{\pi_l^j(t)}{\mathrm{CBL}^j(t)}s^j(t), \tag{9}$$

$$\beta^j(t) = \pi_l^j(t)s^j(t). \tag{10}$$

In this way, the demand resources can be treated as equivalent generation resources and are then able to compete on equal ground with conventional generation resources.

4. Optimal combined scheduling of generation and demand response

Typically, system operators execute generation scheduling with load forecasting, generation unit commitment, and network configuration for the system constraints. DR resources can be included in the generation scheduling with DR scheduling. The objective of the generation and DR scheduling problem is to minimize the system operation cost, including the generation and DR costs, without violating any system operation constraints. The DR constraints, which are the impediments of participation in a DRP, are also proposed in this paper, as well as the conventional generation constraints.

4.1. Objective function of generation and demand response

The cost function of a generation unit i can generally be expressed as a quadratic function of its power output such that [14]

$$C_g^i(P_g^i(t)) = \alpha^i P_g^i(t)^2 + \beta^i P_g^i(t) + \gamma^i s^i(t) + \mathrm{STC}^i b^i(t), \tag{11}$$

where $C_g^i(\cdot)$ is the operation cost of a unit i at time t, $P_g^i(t)$ is the power output, $s^i(t)$ is the unit commitment flag which is 1 or 0 depending on if unit i is on or off, respectively, $STC^i(t)$ is the start-up cost, and $b^i(t)$ is the unit beginning flag when unit i turns on from the off state.

The DR cost function of customer j, $C^j_{DR}(\cdot)$ can be represented from Eq. (5) as

$$C^j_{DR}(DR^j(t)) = \frac{\alpha^j(t)}{2} DR^j(t)^2 + \beta^j(t) DR^j(t), \tag{12}$$

where the subscripts i and j denote generation units and demand resources for the same nomenclature, respectively.

The constant term of the generation cost function usually consists of no-load and start-up costs. The DR cost function represents a customer's demand reduction cost of willingness to pay. This virtual cost function is unrelated to the physical characteristics of the power system. As shown in Fig. 4, where $C^i_g(P^i_g)$ is a conventional generation cost curve with a no-load cost and $C^j_{DR}(DR^j)$ presents the DR cost curve, if the amount of DR reduction is zero, system operators do not pay any incentives. It can be assumed that the no-load cost of the DR cost function is not required.

The start-up cost of the generation cost is a fuel cost required when a generating unit changes from the off state to the on state. This cost can vary greatly according to the physical internal temperature of a unit, whether it is hot-started or cold-started. Similarly, a DR reduction may influence the temperature of the load according to the characteristics, such as electric furnaces, large-sized motors, and cooling devices. However, demand side loads have a wide variety of characteristics, and are unmeasurable and insignificant. Therefore, this paper disregards the start-up cost of DR.

The optimum scheduling of generation and DR can be achieved by minimizing the sum of generation and DR cost such that

$$\min\left\{\sum_{i=1}^{N_g} C^i_g(P^i_g(t)) + \sum_{j=1}^{N_d} C^j_{DR}(DR^j(t))\right\}, \tag{13}$$

where N_g and N_d are the numbers of generation units and demand resources, respectively.

4.2. Generation constraints

The constraints of the objective function of (13) can be categorized into two portions: generation and the DR. The generation constraints are typical, familiar forms [15–18]. The load flow balancing equation and generation limits of a unit i are, respectively,

$$\sum_{i=1}^{N_g} P^i_g(t) + \sum_{j=1}^{N_d} DR^j(t) = \sum_{j=1}^{N_d} CBL^j(t), \tag{14}$$

$$P^i_{g,\min} s^i(t) \leqslant P^i_g(t) \leqslant P^i_{g,\max} s^i(t), \tag{15}$$

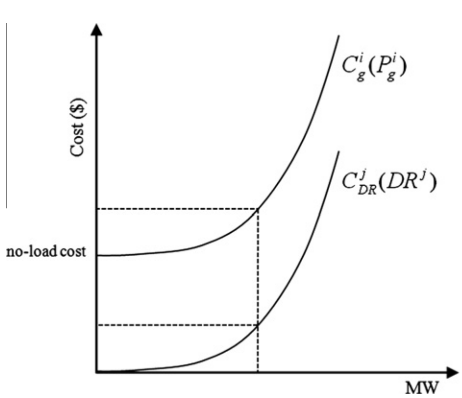


Fig. 4. Generation and DR cost function.

where $P^i_{g,\min}$ and $P^i_{g,\max}$ are the minimum and maximum power outputs of a unit i [MW], respectively.

The ramp rates of a unit i can be written as [15]

$$P^i_g(t) - P^i_g(t-1) \leqslant RU^i, \tag{16}$$

$$P^i_g(t-1) - P^i_g(t) \leqslant RD^i, \tag{17}$$

where RU^i and RU^i are ramp up and ramp down rates of unit i, respectively.

Table 2 shows an example of status flags to describe both minimum up and down times and unit commitment state constraints, which consist of a unit commitment flag and unit beginning and ending flags of a generation unit i. Once a unit is started, it must continue to run for at least the minimum up time. Specifically, when a unit's beginning flag is "1," the accumulation of unit commitment flags $s^i(t)$ from the starting to ending time should be more than the minimum up time. Similarly, a unit should remain idle for the minimum down time before restarting. When a unit's ending flag is "1," the accumulation of complement of a unit's commitment flags, $\overline{s^i}(t)$, from the ending to restarting time should be longer than the minimum down time. Subsequently the minimum up and down times of unit i can be expressed as

$$\sum_{t=b_1}^{e_1} s^i(t) \geqslant MU^i b^i(t), \tag{18}$$

$$\sum_{t=e_1}^{b_2} \overline{s^i}(t) \geqslant MD^i e^i(t), \tag{19}$$

where MU^i and MD^i are the minimum up and down times of unit i [h], respectively, $e^i(t)$ is the unit ending flag of unit i at time t when unit i changes from the on state to the off state, b_1 and b_2 are the starting and restarting times, respectively, and e_1 is the ending time when unit i changes from the on state to the off state.

As illustrated by the example in Table 2, $(b^i(t) - e^i(t))$ is the same as the change in the unit commitment flag between unit time interval, $(s^i(t) - s^i(t-1))$. In addition, since the beginning and ending times of the generating operation never coincide, the sum of both flags cannot be greater than 2. Using the relationship of these flags, the constraints of the unit commitment states of unit i can be rearranged as shown by (20) and (21).

$$b^i(t) - e^i(t) = s^i(t) - s^i(t-1), \tag{20}$$

$$b^i(t) + e^i(t) \leqslant 1. \tag{21}$$

4.3. The demand response constraints

DR constraints include DR magnitude limits, DR ramp rate, DR minimum and maximum duration limits, DR frequency limits, and DR commitment state. These constraints are inferred from DR magnitude, duration and frequency of the registration and participation information.

Table 2
Example of unit commitment states.

	11 h	12 h	13 h	14 h	15 h	16 h	17 h	18 h
$s^i(t)$	0	1	1	1	0	0	0	1
$b^i(t)$	0	1	0	0	0	0	0	1
$e^i(t)$	0	0	0	0	1	0	0	0
$\overline{s^i}(t)$	1	0	0	0	1	1	1	0
$s^i(t) - s^i(t-1)$	0	1	0	0	−1	0	0	1
$b^i(t) - e^i(t)$	0	1	0	0	−1	0	0	1

Fig. 5 illustrates Fig. 1 in detail, including the ramp rates, and shows the demand reduction curve of the demand resources participating in the DRP. DR magnitude $M^j(t)$ was previously defined as the interruptible maximum demand, and thus, DR magnitude limits of customer j are given as

$$0 \leqslant DR^j(t) \leqslant M^j(t)s^j(t). \tag{22}$$

DR ramp rates of customer j are given as

$$DR^j(t) - DR^j(t-1) \leqslant RU^j s^j(t), \tag{23}$$

$$DR^j(t-1) - DR^j(t) \leqslant RD^j s^j(t), \tag{24}$$

where RU^j and RD^j are the ramp up rate and ramp down rate of customer j, respectively.

DR duration, d^j, has minimum and maximum duration limits given as

$$D^j_{\min} \leqslant d^j \leqslant D^j_{\max}. \tag{25}$$

From (3) and (25), the following expression is derived

$$D^j_{\min} \sum_{t \in T} b^j(t) \leqslant \sum_{t \in T} s^j(t) \leqslant D^j_{\max} \sum_{t \in T} b^j(t). \tag{26}$$

For a single DR event, the summation notation can be eliminated from both sides of (26), and the DR commitment flag s^j should be aggregated from b to e, the starting and ending points. Therefore, the limits of the minimum and maximum durations, $D^j_{\min}$ and $D^j_{\max}$, respectively, can be written as

$$D^j_{\min} b^j(t) \leqslant \sum_{t \in b}^{e} s^j(t) \leqslant D^j_{\max} b^j(t). \tag{27}$$

The frequency of participation in the DRP is the sum of the number of past participation events in the DRP and the beginning flag at time t, indicating whether or not to start demand reduction at that time. The actual frequency should have a lower value than that of the maximum DR frequency, which is part of the registration information, and it can be expressed by

$$\sum_{k \in T} b^j(k) + b^j(t) \leqslant F^j. \tag{28}$$

The first term of (28) can be replaced with the frequency rate defined by (4), such that

$$f^j(t)T + b^j(t) \leqslant F^j. \tag{29}$$

The DR commitment states of customer j can be similarly determined as for the case of the unit commitment states in (20) and (21), such that

$$b^j(t) - e^j(t) = s^j(t) - s^j(t-1), \tag{30}$$

$$b^j(t) + e^j(t) \leqslant 1. \tag{31}$$

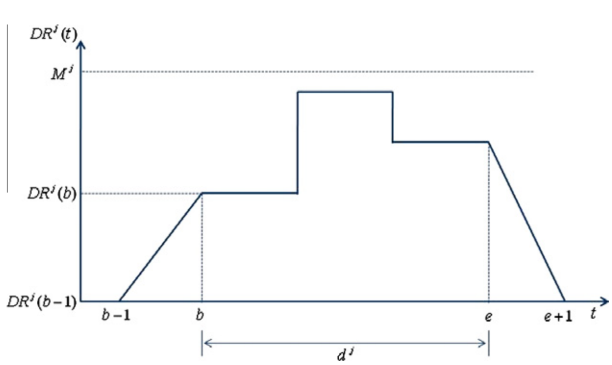


Fig. 5. Demand reduction curve of customer j.

4.4. Demand response uncertainty

Customer behaviors are not as stable as a power generator. Even though the DRP historical information can be collected, there is still a high probability that customers will unexpectedly change their consumption patterns. A customer's behavior is too unstable to simply transform the demand resources into virtual generation resources. However, conventional peak plants have similar situations regarding their failure probabilities, even though the values of probabilities are much smaller than those of demand resources. Basically, the availability and unavailability of a generation unit in the power system are defined based on its historical data, respectively, as [13]

$$\text{Unavailability} = \frac{\sum[\text{down time}]}{\sum[\text{down time}] + \sum[\text{up time}]}, \tag{32}$$

$$\text{Availability} = \frac{\sum[\text{up time}]}{\sum[\text{down time}] + \sum[\text{up time}]}. \tag{33}$$

Generation units participate in the generation scheduling of their own unavailability (or failure probability).

In a similar way, DR availability and unavailability can be defined as illustrated in Fig. 6.

Step 1 in Fig. 6, which is the same as Fig. 1, shows the situation when DR events have been issued and customer j responds to the corresponding DR events. Step 2 shows that the customer participates in the DR 1 event but only partially participates in event 2 without reducing his demand during time t_3. In step 3, the customer participation history is gathered for all of the DR events, where the up and down times of demand reductions show the similarity in the success and failure states of the generation units, respectively. Therefore, similar to (32) and (33), DR unavailability and availability can also be defined using the up and down time data.

Nevertheless, conventional generation scheduling is performed on the day ahead of real time operation with generation units which still have their own failure probabilities, and if a specific generation unit unexpectedly fails during service, the supply shortage can be resolved through a reserve market or ancillary service, without changing the generation scheduling, since there is insufficient time to adjust the generation scheduling during real time operation.

This is similar for DR reduction. The uncertainty of consumption patterns can be predicted with their associated DR unavailability as explained above, and the participation failure can be resolved through a reserve market or ancillary service in close to real time, even though we may need the much greater procurement of reserve or ancillary service due to the larger probability of DR failure compared to that of generation unit failure. The cost of the additional procurement of reserve or ancillary service could be regarded as a potential avoided cost of generation construction.

5. Case study

5.1. Simple 6-bus test system

A case study was conducted for the combined scheduling of generation and DR using the participation and registration information proposed in this paper. The case study is programmed using commercial Matlab with a typical personal computer.

A simple 6-bus test system was used in the case study, as shown in Fig. 7, consisting of five generation units with a total capacity of 316 MW. Table 3 shows the loads of four load buses from the time period 11–15 h, which correspond to the CBL at each bus. The characteristics of five generation units and customer information of the

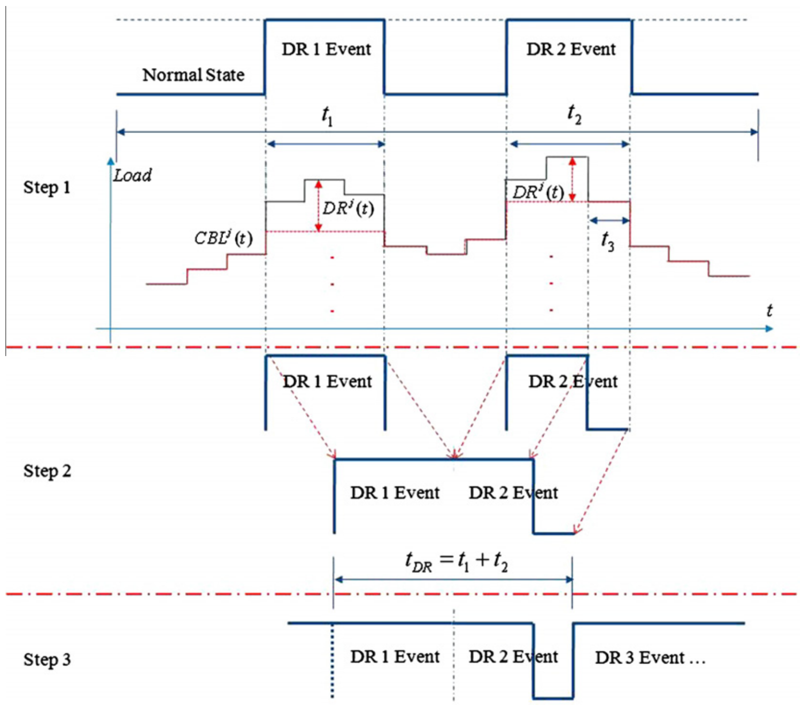


Fig. 6. DR unavailability and availability.

demand resources at the load buses are assumed to be those listed in Tables 4 and 5, respectively.

If all of the customer's participation rates (PRs) are assumed to be 0.2, each load will be reduced by as much as the product of the DR magnitude of the participation information and 0.2. Based on this assumption, the combined schedule of generation (G1–G5) and DR (DR3–DR6) is shown in Table 6 for the cases both without and with DR. The expected load reduction at each load bus is estimated by applying the data in Table 5 to the optimal scheduling formulation in (13) along with the generation and DR constraints. Table 5 shows that the DR events at each load bus are newly generated and issued at the case with DR, especially from hours 11 to 15. This is a result of the demand resources with a lower marginal price having replaced the generation with a higher price. The total costs are also reduced compared with the case 'without DR.'

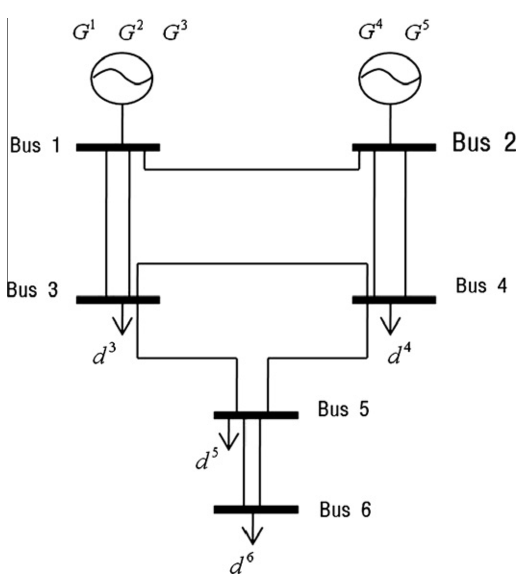


Fig. 7. Case study test system.

Table 3
System demand [MW].

	11 h	12 h	13 h	14 h	15 h
Load 3	80	85	100	110	85
Load 4	70	70	80	80	60
Load 5	60	65	70	70	60
Load 6	50	50	50	50	45

The actual demand resource's reactions are assumed in Table 7 for the case 'with DR,' while Table 6 is the expected results calculated by the optimal scheduling formulation. The demand resources of DR 3 in Table 7 reduced their demand in parallel with the DR event which occurred in the DR schedule shown in Table 6, while the demand resources of DR 4 reacted with lowered reductions compared to the DR schedule. The actual reactions against the scheduled optimal DRP were used to estimate the new participation information in Table 8, as well as to obtain new demand curves according to the PR values.

Fig. 8 shows supply curve and demand curves for the cases of PR values 1, 0.2 and 0, especially at hour 14, as shown in Table 7. In

Table 4
Characteristics of the generation units.

	G1	G2	G3	G4	G5
Generation cost coefficients					
α^i	0	0	0	0	0
β^i	0.050	3.0	5.250	1.545	1.323
γ^i	44.29	95.542	180	60	72.5
Ramp up rate (MW/h)	30	36	20	20	20
Ramp down rate (MW/h)	30	36	20	20	20
Min up time (h)	3	2	2	3	3
Min down time (h)	3	1	1	3	3
Max generation (MW)	120	36	20	80	60
Min generation (MW)	30	0	0	20	15

Table 5
Customer information of the demand resources.

DR	Customer information	11 h	12 h	13 h	14 h	15 h
DR 3	DR magnitude (MW)	10	10	10	10	10
	Min duration (h)	1				
	Max duration (h)	3				
	Frequency (freq/yr)	10				
	α^3	1.72	1.72	1.72	1.72	1.72
	β^3	70	70	70	70	70
DR 4	DR magnitude (MW)	8	8	8	8	8
	Min duration (h)	1				
	Max duration (h)	5				
	Frequency (freq/yr)	10				
	α^4	2.72	2.72	2.72	2.72	2.72
	β^4		74	74	74	74
DR 5	DR magnitude (MW)	7.5	7.5	7.5	7.5	7.5
	Min duration (h)	1				
	Max duration (h)	5				
	Frequency (freq/yr)	10				
	α^5	4	4	4	4	4
	β^5	130	130	130	130	130
DR 6	DR magnitude (MW)	5	5	5	5	5
	Min duration (h)	1				
	Max duration (h)	5				
	Frequency (freq/yr)	10				
	α^6	3.6	3.6	3.6	3.6	3.6
	β^6	98	98	98	98	98

Table 6
Optimal combined scheduling of generation and DR in the test system [MW].

		11 h	12 h	13 h	14 h	15 h
Without DR (PR = 0)	G1	120	120	120	120	120
	G2	0	10	36	36	0
	G3	0	0	4	14	0
	G4	80	80	80	80	70
	G5	60	60	60	60	60
	Cost ($)	1033.31	1063.31	1162.31	1214.81	1017.86
With DR (PR = 0.2)	G1	120	120	120	120	120
	G2	0	6.4	36	36	0
	G3	0	0	0	7.9	0
	G4	80	80	80	80	70
	G5	60	60	60	60	60
	DR 3	0	2	2	2	0
	DR 4	0	1.6	1.6	1.6	0
	DR 5	0	0	0	1.5	0
	DR 6	0	0	0.4	1	0
	Cost ($)	1033.31	1060.30	1150.54	1200.18	1017.86

Table 7
Actual generation addition and demand reduction in the test system [MW].

		11 h	12 h	13 h	14 h	15 h
With DR (PR = 0.2)	G1	120	120	120	120	120
	G2	0	7	36	36	0
	G3	0	0	0.6	11.6	0
	G4	80	80	80	80	70
	G5	60	60	60	60	60
	DR 3	0	2	2	2	0
	DR 4	0	1	1	0	0
	DR 5	0	0	0	0	0
	DR 6	0	0	0.4	0.4	0

Fig. 8, the electricity prices when starting and ending to respond to the DRP are assumed for each case, and these values are used to estimate the coefficients, α^j and β^j, of the marginal cost for each demand resource. These coefficients can be estimated for all of the other hours in a similar way. The values are shown in Table 8 which includes all of the participation information, where "–" denotes no DR event issued, and "0" denotes no reduction in spite of a DR event. This participation information could be used as a reference for the next DR scheduling.

In addition to the cases of PR 0 and 0.2, as shown in Table 6, all the cases of PR 0.4–1.0 in incremental steps of 0.2 are performed, and the results are shown in Fig. 9. It can be seen that the operation costs decrease as PR increases due to higher participation in the DRP.

Fig. 10 shows the curve for the operation cost versus the participation rate (PR) at the specific time of hour 14, where the curve has a negative slope. When the PR is above 5, the operation cost converges at a specific point (1119.3), which implies that the operation cost could not be further improved regardless of an increase in the demand resources. The development of available new DR resources plays a major role in DR enhancement but requires significant cost. Therefore, the DR operators are able to decide on new DR development policies by comparing DR resource development cost with a variation in the operation cost. Operators tend to invest

Table 8
New participation information of demand resources.

DR	Participation information	11 h	12 h	13 h	14 h	15 h
DR 3	Participation rate	–	0.2	0.2	0.2	–
	Load response rate	–	0.0235	0.02	0.0182	–
	DR duration	3				
	DR frequency rate	0.04167				
	α^3	–	20	25	22.5	–
	β^3	–	70	70	130	–
DR 4	Participation rate	–	0.2	0.2	0.2	–
	Load response rate	–	0.1429	0.0125	0	–
	DR duration	2				
	DR frequency rate	0.04167				
	α^4	–	47.172	36.25	Infinite	–
	β^4	–	110	120		–
DR 5	Participation rate	–	–	–	0	–
	Load response rate	–	–	–	0	–
	DR duration	0				
	DR frequency rate	0				
	α^5	–	–	–	0	–
	β^5	–	–	–	0	–
DR 6	Participation rate	–	–	0.08	0.08	–
	Load response rate	–	–	0.008	0.008	–
	DR duration	2				
	DR frequency rate	0.04167				
	α^6	–	–	83.667	112.25	–
	β^6	–	–	200	175	–

in demand resource development when DR development cost is lower than the variation of the operation cost to DR, which can be expressed as

$$\alpha \cdot \Delta \mathrm{DR} \leqslant \Delta cost, \tag{34}$$

where ΔDR is the available capacity to develop the demand resource [MW], $\Delta cost$ is a variation of the operation cost, and α is the demand resource development cost [$/MW]. Rearranging (1) and (34) results in

$$\alpha \leqslant \frac{\Delta cost}{M \cdot \Delta \mathrm{PR}}. \tag{35}$$

Fig. 11 shows the incremental operation costs of Fig. 8 divided by a change of PR, where the area below the curve is the region where the development cost α is lower than the variation of operation cost, implying an investable region for new DR resources development.

5.2. Modified IEEE 24-bus RTS

A case study was conducted for the combined scheduling in a larger power system as a bench mark, using a modified IEEE 24-bus RTS (Reliability Test System), as shown in Fig. 12 [19].

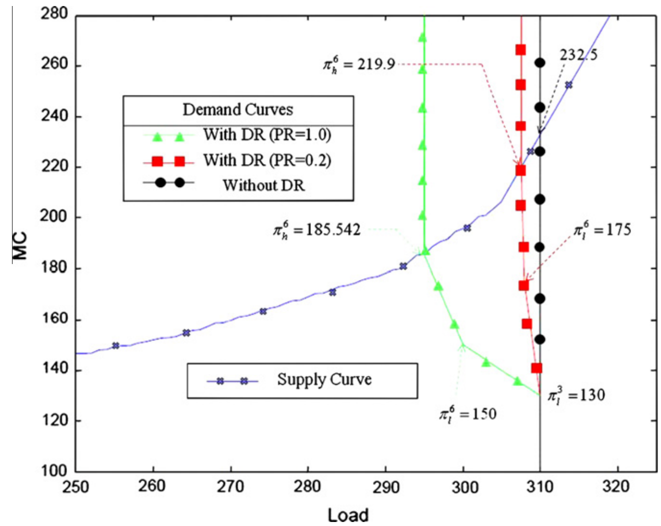


Fig. 8. Supply and demand curves according to actual customer responses.

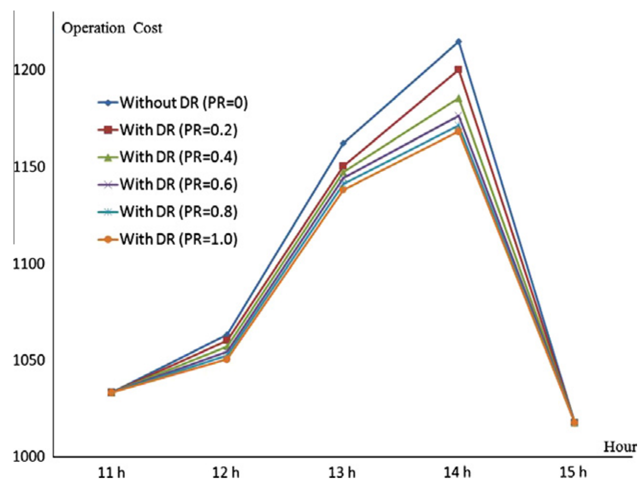


Fig. 9. Operation cost for different PRs.

The system consists of 11 generation units with a total capacity of 1470 MW. The number of load buses is 18, and the loads at each bus were assumed for 24 h, corresponding to the CBL for each bus. Among the 18 load buses, demand resources were assumed to be available only at seven load buses, marked with circles in Fig. 12. Characteristics of the 11 generation units and customer information of the seven demand resources at load buses are given in Tables 9 and 10, respectively, where the numbers for the generation

Table 9
Generation unit characteristics.

	Generation cost coefficients			Start-up cost	Ramping rate (MW/h)		Min. up time (h)	Min. down time (h)	Generation limits (MW)	
	α^i	β^i	γ^i	STC^i	Up	Down			Min.	Max.
G1	0.008	18.325	30	40	50	50	2	1	0	50
G2	0.0085	25.324	20	20	20	20	1	1	0	20
G7	0.077	30.120	0	0	12	12	1	1	0	12
G13	0.0075	10.546	30	80	50	50	7	7	0	50
G14	0.0075	8.020	50	150	60	60	8	8	0	60
G15	0.008	6.341	50	140	70	70	4	8	0	76
G16	0.005	4.123	100	300	50	50	8	8	30	100
G18	0.001	1.213	400	800	20	20	1	1	150	400
G21	0.002	2.678	180	400	50	50	48	24	100	350
G22	0.002	3.231	150	400	40	40	10	12	50	197
G23	0.005	3.451	100	300	50	50	8	8	50	155

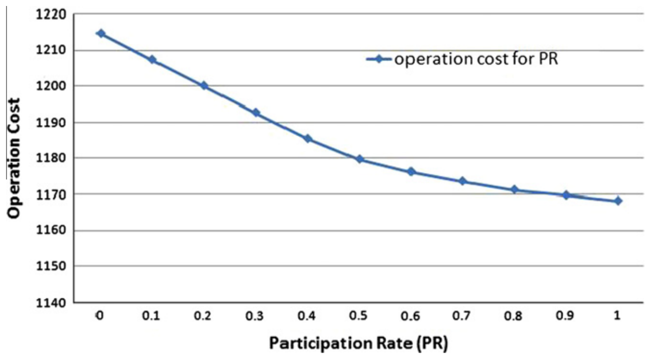


Fig. 10. Operation cost for PRs at hour 14.

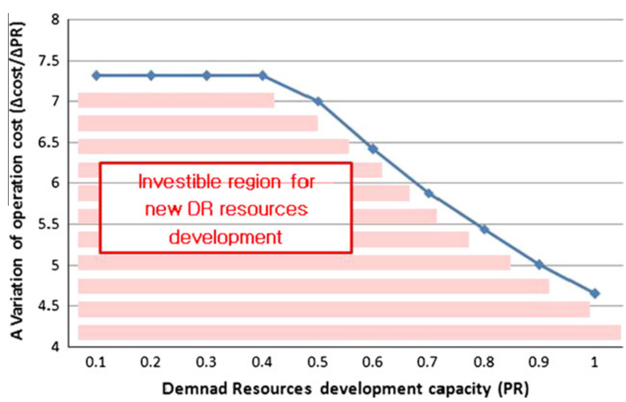


Fig. 11. Variation of incremental operation cost with available development capacity.

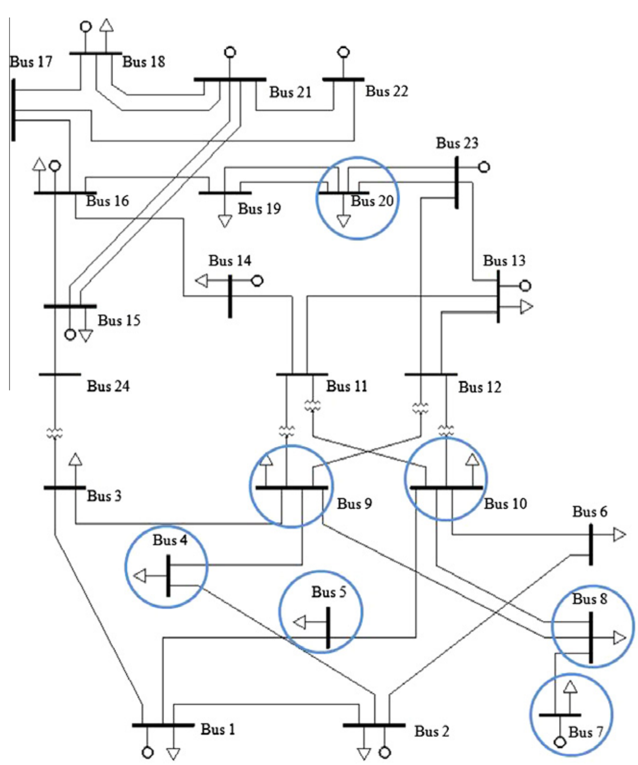


Fig. 12. Modified IEEE 24-bus RTS.

units and demand resources are defined by the bus numbers at their connection points.

Fig. 13 shows the generation schedule without DR. If demand resources are involved in generation scheduling during the period from hours 14 to 21, then the combined schedule with DR is shown in Fig. 14, where it is partially magnified during the peak time in order to ascertain the detailed replacement effect of competitive DR. Comparing Figs. 14 and 13, it can be observed that demand resources DR4, 5, 8 and 10 have replaced generation units G1, 2 and 7, which have higher marginal costs. Among the replaced generation units, G2 and G7 are completely turned off, and G1 is partially loaded even though the marginal cost of G1 is greater than those of DR4, 5, 8 and 10 because the total amount of reduction demand involved is less than the total capacity of the inactive generation units. Therefore, G1 becomes a marginal generator which can determine the SMP (System Marginal Price), instead of G7 or G2. This DR replacement contributes to lower the SMP as well as the peak load during the peak time.

Table 11 shows the change in cost of the generation and combined schedule by tightening the generation and DR constraints, where the ramp rate of G15 changes from 70 to 60 [MW/h], the minimum down time of G1 changes from 1 to 2 h for generation constraints, and the frequency rates of DR4 and DR5 change from 8 to 9 for the DR constraints. Table 11 shows that costs are reduced due to the DR effect and increased due to the additional generation and DR constraint.

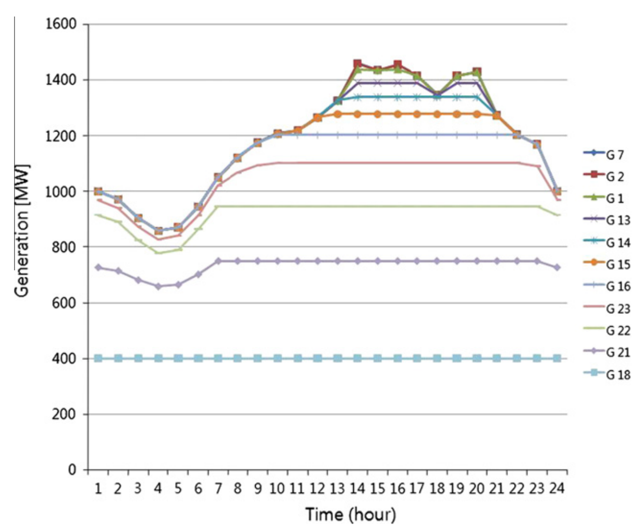


Fig. 13. Generation schedule without DR.

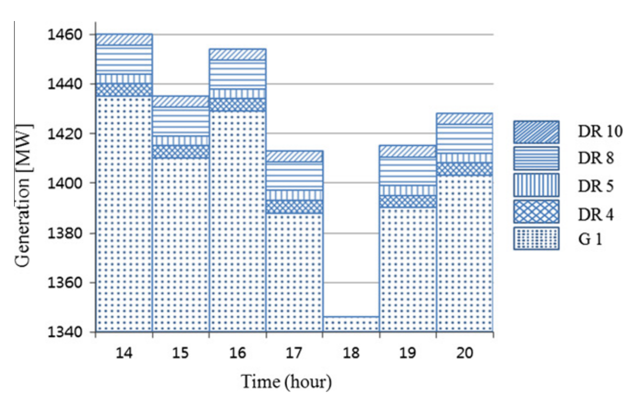


Fig. 14. Combined schedule with DR.

Table 10
Customer information of demand resources.

	Participation rate	DR magnitude (MW)	Duration (h)		Frequency (freq/yr)	Frequency rate (freq/yr)	Marginal cost coefficients	
	PR^j	M^j	Min. D^j_{min}	Max. D^j_{max}	F^j	f^j	α^j	β^j
DR4	0.5	10	2	4	10	8	0.02	15.12
DR5	0.5	8	2	4	10	8	0.034	15.12
DR7	0.5	9	2	4	10	4	0.034	40
DR8	0.5	23	2	4	10	7	0.114	17.1
DR9	0.5	9	2	4	10	2	0.034	35.2
DR10	0.5	9	2	4	10	4	0.034	18.12
DR20	0.5	12	2	4	10	8	0.074	20.1

Table 11
Cost effects of generation and DR constraints [$].

	13 h	14 h	15 h	16 h	17 h	18 h	19 h	20 h	21 h	22 h
Case A	5761	7998	7210	7695	6832	5840	6872	7077	5122	4645
Case B	5761	7998	7210	7695	6832	5840	7116	7117	5133	4656
Case C	5761	7753	7161	7519	6765	5840	6831	7031	5122	4645
Case D	5761	7753	7161	7519	6765	5840	6831	7031	5122	4645
Case E	5761	7753	7161	7519	6765	5840	6860	7062	5122	4645

Case A: Generation schedule (base case).
Case B: Case A + generation constraints.
Case C: Combined schedule (Case A + DR effects).
Case D: Case C + generation constraints.
Case E: Case C + generation constraints + DR constraints.

6. Conclusions

The modeling of customer information was proposed in order to represent customer response characteristics in a DRP and to describe how to participate in the power market. A new concept of virtual generation resources converted from demand resources was also introduced to determine the optimal combined scheduling of generation DR in power systems. The marginal cost function of virtual generation resources was expressed with the proposed customer information. The DR constraints expressed with various status flags and customer information, as well as generation constraints, were presented to model the restrictive conditions of customer participation in a DRP. The optimal combined scheduling with generation and DR was conducted to minimize the operation cost of a power system with customer information.

In the case study, the optimal combined schedule of generation and DR was obtained, and the participation information and marginal cost function of the demand resources were estimated from actual demand reduction data. Results indicate that operation costs obtained from optimal scheduling decrease as the PR increases, and the deviation in operation costs by varying the PR presented desirable investment plans in new DR resource development.

It would be highly desirable to continue with additional research into the uncertainty of the demand response.

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